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Alberta Energy

Annual Report
1992 - 1993

January 1994

The Honourable Stanley S. Schumacher
Speaker of the Legislative Assembly
Province of Alberta

Mr. Speaker:

I have the honour of submitting the Annual Report of the Alberta Department of Energy for the fiscal year ending March 31, 1993.

Respectfully submitted,

Patricia Black

Patricia L. Black
Minister of Energy

January 1994

The Honourable Patricia Black
Minister of Energy

Dear Minister:

It is my pleasure to submit the Annual Report of the Alberta Department of Energy for the fiscal year 1992-93. The report contains a summary of the Department's activities, revenues and expenditures for the year.

Respectfully submitted,

David J. Manning

David J. Manning, Q.C.
Deputy Minister of Energy

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Minister's Message

The year 1992-93 witnessed the beginning of a welcome turnaround in the province's oil and gas industry.

After a prolonged period of reduced activity, retrenchment and major layoffs, the energy picture brightened considerably. Idle rigs began working again. Sales of petroleum and natural gas leases picked up. And, as optimism returned to the industry, so did much-needed investment.

Several factors helped bring about this increased activity, including low interest and exchange rates, strengthening gas prices and extensive corporate restructuring that left companies much better positioned to operate profitably in the '90s.

The Alberta government played a significant role in the turnaround. In October 1992, after months of working closely with industry, the government announced comprehensive changes to the oil and natural gas royalty system to bring it in line with the current economic conditions.

This marked the first major adjustment to royalties since the 1970s. Changes introduced at that time were based on the assumption that oil and gas prices would continue to rise. Since 1985, however, prices have declined significantly, resulting in an industry-wide slowdown.

The new 1992 measures not only reduced royalties but modified the royalty formula to make it more price sensitive. A lower third-tier royalty formula was also introduced, along with provisions to encourage investment in aging pools and the use of new technology to recover oil in place.

Overall, the goal of these and other changes was to stimulate Alberta's energy industry — to spur activity, employment and investment. By the end of the fiscal year, this goal was being achieved.

It is encouraging to see the signs of renewed vitality in the oil and gas sector, a driving force for the provincial economy. When this sector is strong and healthy, all Albertans stand to gain.

Fully realizing this, the Department is continuing to work with industry on simplifying administration of natural gas royalties. A simplified process for natural gas and byproduct royalties administration will be implemented in 1994.

Work also proceeded with the second phase of the comprehensive royalty review. In this phase, the Department is examining the royalties on natural gas byproducts plus simplifying administration for natural gas byproducts, enhanced oil recovery and the freehold mineral tax. When the review is completed, a recommendation will be prepared for Cabinet.

The royalty structure for coal was also revised and simplified, in full consultation with industry. The new system, replacing one introduced in 1976, should prove to be more responsive to the difficult economic conditions currently facing industry.

A long-term goal was realized in November with the official opening of the Bi-Provincial Upgrader in Lloydminster.

This upgrader — jointly owned by Husky Oil Ltd. and the governments of Canada, Alberta and Saskatchewan — will play a key role in the development of our abundant heavy oil and bitumen resources.

With the conversion of these substances into a high-quality synthetic crude, value is added to our resources before they leave the West.

Oil sands and heavy oil are becoming increasingly important in Alberta's energy picture as conventional reserves decline. Already they account for 20 per cent of Canada's crude production, and this figure is expected to grow in the coming years.

Cooperative action between industry and the various levels of government is necessary if Canada is to fully realize the economic benefits of Alberta's oil sands and heavy oil resources. During this fiscal year, two such initiatives were announced.

The first initiative calls for establishing a National Centre for Upgrading Technology at Devon, drawing on the expertise of both the Canadian Centre for Mineral Energy and Technology (CANMET) and the Alberta Research Council. The second initiative will see creation of a National Task Force on Oil Sands Strategies.

During May and June 1992, a panel established to review Alberta's Electric Energy Marketing Act held public hearings in Lethbridge, Grande Prairie, Edmonton, Fort McMurray and Calgary to hear submissions from interested Alberta organizations and individuals. In addition, more than 550 written submissions were received.

The panel found that EEMA, implemented in 1982, has been effective in achieving its main objective — the reduction of electricity rate disparities across the province through equalization of wholesale electricity costs. However, it concluded that there is an unfair element in the EEMA pricing formula.

Although there was a great deal of public input during the panel's review, we believe that on such a far-reaching issue those who made representations should have an opportunity to comment on the recommendations. Copies of the report were sent to these participants.

Further progress was made during the year on the Clean Air Strategy for Alberta (CASA), an initiative launched in 1990 by the Ministers of Energy and Environment in response to growing concerns over the impact of fossil fuels on global climate change, acid deposition and smog.

In June, the government announced its support of the key recommendations made by a multi-stakeholder advisory group following 18 months of public consultation across Alberta.

The Department chairs the CASA Interdepartmental Coordinating Committee, responsible for carrying out the approved priority tasks. The Department also chairs 7 CASA priority task groups which address energy efficiency, electricity policy, and national and regional coordination.

It has been a year of challenge and accomplishment for the Department. Once again I salute the management and staff for their dedicated work during the past 12 months. These are the people who keep the Department functioning so well, and I gratefully acknowledge the contribution they have made.

Patricia Black

Patricia Black
Minister of Energy

Organizational Structure

The Alberta Department of Energy has four basic functions. It grants mineral rights and administers mineral agreements on behalf of the province; it provides policy recommendations and advice on energy to the government; it advises on, establishes and administers the fiscal regimes and royalty systems through which the people of Alberta — the resource owners — receive fair return on their resources; and it administers energy-related research, development and conservation programs.

In addition to the Department, the Minister of Energy has responsibility for five reporting boards and agencies:

- Alberta Oil Sands Equity
- The Alberta Petroleum Marketing Commission
- Alberta Oil Sands Technology and Research Authority
- Board of Directors of the Alberta Office of Renewable Energy Technology
- The Public Utilities Board.

The Energy Resources Conservation Board reports to Executive Council through the Minister of Energy.

The Department is divided into five divisions, including Finance and Administration which also served Alberta Forestry, Lands and Wildlife in the 1992-93 fiscal year. In addition to the five divisions, the Department's organizational structure includes the Communications Branch and Legal Services, both reporting to the Deputy Minister.

Mineral Resources Division — This division is responsible for developing and administering energy and other mineral leasing policies to optimize Alberta's mineral supply and the province's corresponding economic, environmental and employment interests. The division ensures that the Alberta Geological Survey effectively and efficiently supports provincial geological requirements. It consults with other governments on leasing-related and geological survey policies and administrative practices.

Mineral Revenues Division — This division is responsible for the management of programs established to generate and collect mineral revenues and for providing the assurance that these programs are consistent with provincial policies and the business environment. It manages a number of incentive programs that enhance exploration and development of minerals in Alberta and their extraction.

Markets, Supply and Industry Analysis Division — This division serves the Alberta public interest through analysis, policy development, making recommendations on legislation and programs, and providing information in the areas of markets, regulatory matters, industry financial performance, supply economics, resource revenue forecasting and electricity policy. The division provides advice on how to optimize the value and benefits that Albertans receive as owners of their mineral resources and consumers of oil, gas, coal and electricity.

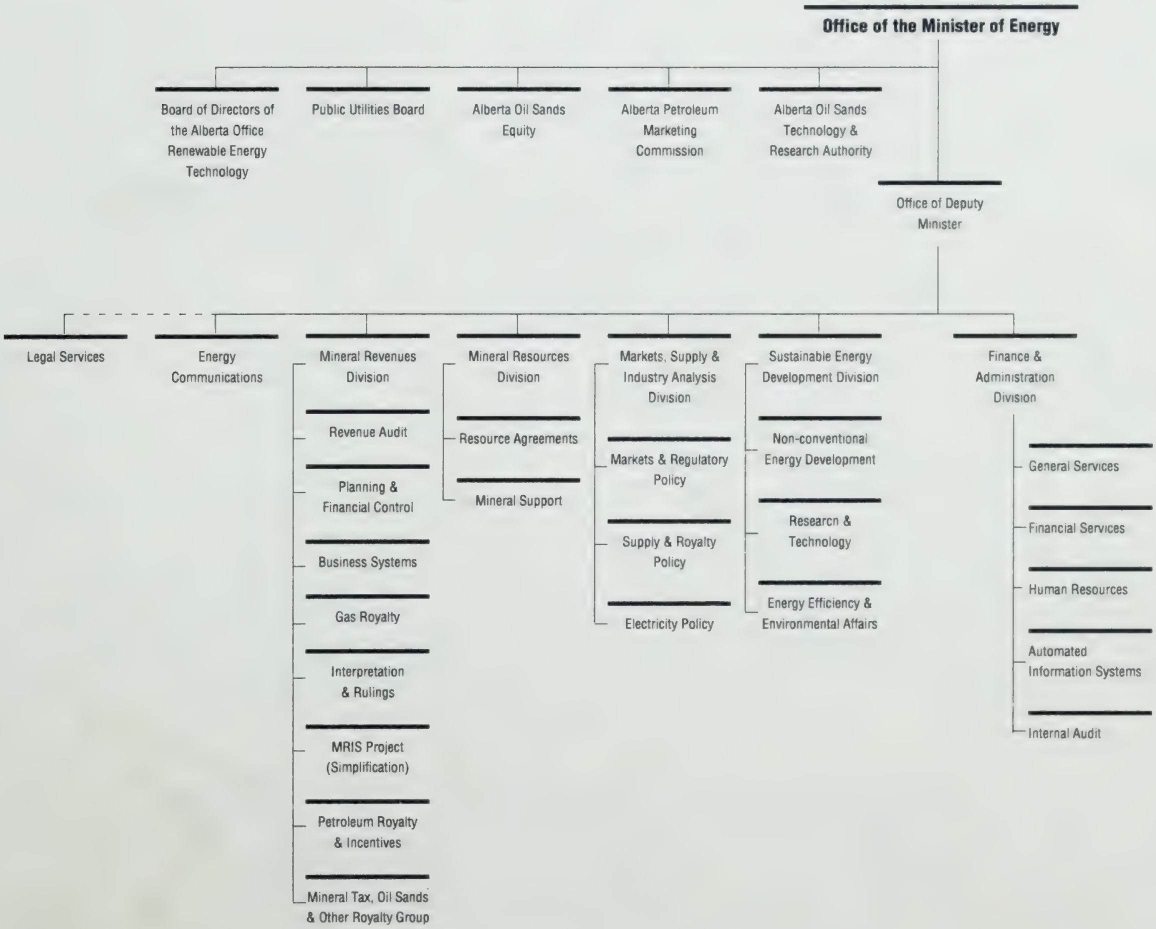
Sustainable Energy Development Division — This division works to ensure the sustainable development of Alberta's energy resources. It provides policy advice and administers programs concerning energy efficiency. It also provides policy advice concerning environmental issues affecting energy production and use. The division undertakes analysis and provides policy advice concerning development of non-conventional resources, including oil sands and renewable energy. It also provides advice on research and technology and administers programs involving coal, hydrogen and renewable energy. The division has extensive liaison with other Alberta government departments and agencies and with industry, non-governmental organizations and consumers.

Finance and Administration Division — This division provides services in the areas of finance, internal audit, automated systems, accommodations, records management, the Crown Land Registry, document and information support, and human resource programs. It provides a sophisticated structure for the financial and administrative functions required by both departments. The division served both the Department of Energy and the Department of Forestry, Lands and Wildlife in the 1992-93 fiscal year.

Communications — The Communications Branch provides an array of services to help ensure that the general public is kept informed of the Department's activities and responsibilities. The branch prepares written material for release to the news media and is responsible for advertising, production of publications and development of displays. The branch provides writing and editing services and coordinates printing, graphic design and photography services. In cooperation with divisional staff, the branch develops and implements public awareness campaigns and responds to enquiries from the media.

Legal Services — This division provides legal advice and assistance on all matters pertaining to energy. It also served the Department of Forestry, Lands and Wildlife in the 1992-93 fiscal year.

Figure 1
Organization Chart for the Department of Energy

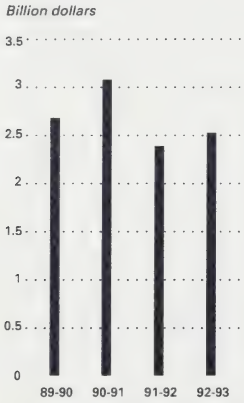

Office of the Minister of Energy
Board of Directors of the Alberta Office Renewable Energy Technology
Public Utilities Board
Alberta Oil Sands Equity
Alberta Petroleum Marketing Commission
Alberta Oil Sands Technology & Research Authority
Office of Deputy Minister
Legal Services
Energy Communications
Mineral Revenues Division
Revenue Audit
Planning & Financial Control
Business Systems
Gas Royalty
Interpretation & Rulings
MRIS Project (Simplification)
Petroleum Royalty & Incentives
Mineral Tax, Oil Sands & Other Royalty Group
Mineral Resources Division
Resource Agreements
Mineral Support
Markets, Supply & Industry Analysis Division
Markets & Regulatory Policy
Supply & Royalty Policy
Electricity Policy
Sustainable Energy Development Division
Non-conventional Energy Development
Research & Technology
Energy Efficiency & Environmental Affairs
Finance & Administration Division
General Services
Financial Services
Human Resources
Automated Information Systems
Internal Audit

Revenues

As owners of the province's natural resources, the people of Alberta are entitled to a fair return on the production of oil, natural gas, coal and other minerals. As a representative of the people, the Alberta government, through the Department of Energy, has the responsibility to develop and manage programs to determine these revenues and to collect them.

Total Energy Revenues — Crown revenue in 1992-93 from all mineral resources was derived mainly from royalties and sales of Crown agreements for development of these resources. Net revenue climbed to $2.5 billion from $2.38 billion the previous fiscal year on the strength of higher royalties for natural gas, synthetic crude oil and bitumen (Figure 2).

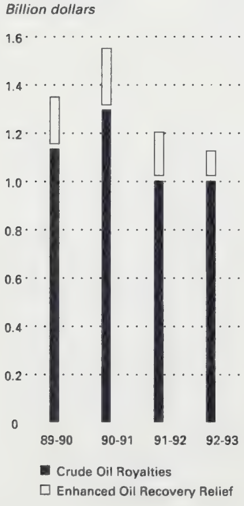
Figure 2
Energy Revenue



Crude Oil Royalties — The volume of Crown conventional oil produced in 1992-93 increased by 1 million barrels from the previous fiscal year to a total of 274.3 million barrels. The gross Crown royalty share — Alberta's share before deductions — represented 23 per cent of the volume produced during the fiscal year compared with 23.5 per cent in 1991-92. New oil, primarily from reservoirs discovered since 1974, represented 77.3 per cent of the Crown volume produced. Light and medium crude oil represented 80.2 per cent of total Crown production.

Net Royalty Volumes and Revenue — The net Crown royalty share reflects deductions for Enhanced Oil Recovery relief and the Oil Royalty Holiday programs — which encourage exploratory and development drilling — from the gross Crown royalty share. The net share totalled 18.3 per cent, a volume of 50.2 million barrels. This compares with a rate of 18.7 per cent and a volume of 51.1 million barrels in 1991-92. Net royalty revenues for crude oil decreased by $30 million to $1 billion (Figure 3).

Figure 3
Crude Oil Royalties



Enhanced Oil Recovery (EOR) — EOR projects are undertaken to increase the recovery percentage of the original oil in place in a particular reservoir. Only about 40 per cent of the oil in a reservoir can be recovered using conventional primary and secondary recovery methods. An additional 10 to 25 per cent of the oil may be recovered with tertiary methods. These include injection of gas and natural gas liquids which mix with the reservoir oil. Additional natural gas, called "push gas," is then injected to force this mixture and the resident oil to producing wells.

These tertiary methods are expensive, and the Crown shares in certain costs by reducing royalties on the tertiary oil produced from the approved EOR project. These royalty reductions are authorized under section 11 of the Petroleum Royalty Regulation.

For the 1992-93 fiscal year, industry received $129.8 million in royalty relief. This relief is provided in-kind, meaning that EOR project participants receive oil in lieu of cash. For the 1991-92 fiscal year, industry received $170.2 million in relief. The drop in relief for the 48 approved projects is primarily due to declining costs as these projects mature.

Roughly 120,000 barrels per day of tertiary oil were recovered from these projects in 1992-93, compared with 130,000 barrels per day in 1991-92.

	1992-93	**1991-92**
	($ millions)	
Crude Oil Royalty Revenue	1,139	1,208
Deduct Enhanced Oil Recovery Relief	130	170
Crude Oil Royalties (net)	**1,009**	**1,038**

Note:EOR relief is for volumes only. It does not include any cash adjustments as provided in the 1991-92 annual report.

Synthetic Crude Oil and Bitumen Royalties — Revenue from the production and sale of synthetic crude oil and bitumen in 1992-93 increased by 110 per cent to $65 million. The increase is a direct reflection of the

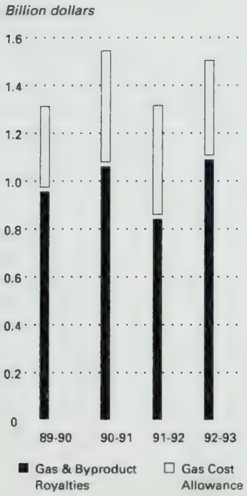
Crown Conventional Oil is oil recovered under authority of a Crown lease, using primary production techniques.

Synthetic Crude Oil is produced from a heavy hydrocarbon called **"bitumen"** which saturates beds of sand in the Athabasca, Peace River and Cold Lake deposits in Alberta. At room temperature, bitumen has the consistency of very cold molasses.

During processing, the carbon level of the bitumen is reduced and the hydrogen level increased. The result is synthetic crude which has properties similar to a high-grade conventional crude oil.

profit-based royalty regimes in place for the two Fort McMurray oil sands plants. These plants suffered losses in the late 1980s when the price of synthetic crude oil remained considerably below the cost of production. The facilities are now operating at a profit and, as a result, the Crown receives a much-improved flow of royalties.

Figure 4
Natural Gas and Byproduct Royalties



Natural Gas and Byproduct Royalties — Overall gross natural gas and byproduct royalty revenues climbed to $1.5 billion for 1992-93 from $1.3 billion in the previous fiscal year due to a tighter market balance and strengthening natural gas prices. Net natural gas and byproduct royalties increased to $1.1 billion from $0.8 billion in the previous fiscal year. (Figure 4)

Gas Cost Allowance — Gas Cost Allowance is a deduction allowed by the Crown for gathering, compressing and processing the Crown's share of natural gas and associated byproducts. It is deducted from royalties payable on a monthly estimated basis. The actual allowance is then calculated and reconciled for each calendar year. The allowance is subtracted from gross royalties to arrive at net royalties payable. In 1992, Gas Cost Allowance totalled $417 million, down 13 per cent from $481 million in 1991.

Gas Royalties ($)	**1992-93**	**1991-92**	**% Change**
	(millions)		
Gas — New	796	643	23.8
Gas — Old	330	306	7.8
Pentane — New	135	132	2.3
Pentane — Old	112	107	4.7
Butane	48	46	4.4
Propane	54	50	8.0
Sulphur	11	36	-69.4
TOTAL	1,486	1,320	2.6
Deduct			
Gas Cost Allowance	417	481	-13.3
Net Gas Royalties	1,069	839	27.4

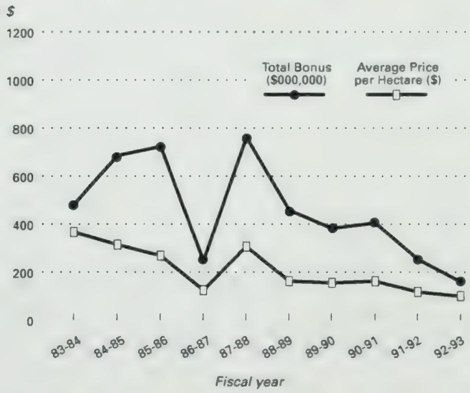
Coal and Other Royalties — Coal royalty income dropped to $16 million in 1992-93 from $26 million in the previous fiscal year. The profitability of the province's bituminous mines was affected by a continuing world supply glut, intense price competition from other exporting countries and the cost of transporting Alberta coal to seaports.

Freehold Mineral Rights Tax — The Freehold Mineral Rights Tax is calculated on a calendar-year basis, based on the value of the petroleum and natural gas recovered from freehold lands.

For the 1991 taxation year, 4,800 freehold titles produced tax assessments of $76.5 million, with net tax realized totalling $75.2 million. In 1992, a total of 4,700 titles generated a tax levy of $73.9 million, consisting of $30 million from natural gas rights and $43.9 million from petroleum rights. The net tax assessment in 1992 was $72.6 million, $1.3 million less than the total levy because of tax incentives associated with enhanced oil recovery activity.

Public Offering of Petroleum and Natural Gas Rights — Revenues from the public offering of 4,561 petroleum and natural gas agreements during the 1992-93 fiscal year totalled $167.4 million compared with $261.5 million in the previous year. These rights sold for an average of $106.90 per hectare against $124.56 the previous year. A 10-year comparison of the revenues received for the public offering of petroleum and natural gas rights is shown in Figure 5.

Figure 5
Public Offering of Petroleum and Natural Gas Rights
Average Price per Hectare and Total Bonuses by Fiscal Year



Freehold Minerals: Mineral rights not owned by the Alberta Crown are called "freehold." They cover about 19 per cent of the 66 million hectares of land in the province. Freehold rights are owned by the federal government within national parks and on behalf of Aboriginals within Indian reserves, by the Hudson's Bay Co. and national railway companies. They also result from federal grants to original homesteaders.

Two areas attracted significantly higher than average revenues for petroleum and natural gas rights. In the Gull Lake area, 19 parcels sold for a total of just over $3 million. The average price per hectare for these parcels was approximately $713. Continuing the trend set in 1991-92 in the Taber area, 34 parcels in that region sold for a total of just over $3 million, with an average price per hectare of approximately $800.

Direct Purchases — The direct purchase of petroleum and natural gas rights was discontinued by the Department on July 9, 1991, except in special circumstances. Revenues from the direct purchase of 4 petroleum and natural gas agreements during the 1992-93 fiscal year totalled $142,183. These rights sold for an average price of $89 per hectare.

Mineral Agreements

The Alberta Crown owns mineral rights covering approximately 81 per cent of the 66 million hectares in the province. Mineral rights not owned by the Alberta Crown are termed "freehold." Whether publicly or privately owned, mineral resources in Alberta have always been privately developed. Before minerals owned by the Alberta Crown can be developed or recovered, the developer must hold an agreement for those minerals, although an agreement is not necessary to perform geophysical work.

Issued by the Mineral Resources Division, mineral agreements consist of permits, licences or leases. Figure 6 depicts the number of active agreements in place for the 1992-93 fiscal year and the number of hectares involved.

Petroleum and Natural Gas Agreements — The Mineral Resources Division issues two types of petroleum and natural gas agreements: licences and leases. Both types may be acquired at sales by public tender.

Petroleum and natural gas leases have a five-year term. Petroleum and natural gas licences, however, have terms of two, four or five years in the Plains, Northern and Foothills areas of the province, respectively. This feature recognizes that access to land is year-round on the Plains and seasonal elsewhere.

Public Offerings — During the 1992-93 fiscal year, 23 public offerings were held in Calgary and 4,561 petroleum and natural gas agreements were sold, down from 5,336 the previous year. These agreements, comprising both leases and licences, encompassed approximately 1.6 million hectares. Figure 7 depicts the number of agreements and hectares sold by public tender since 1977-78, the first full year under the current tenure system.

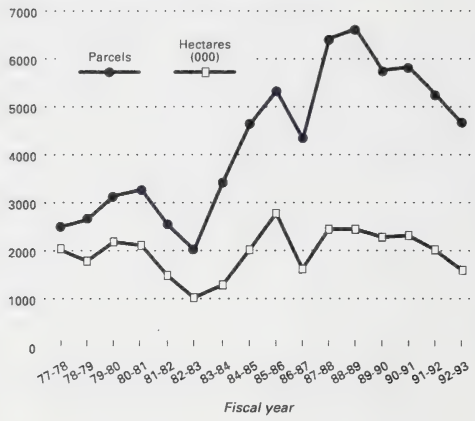
Direct Purchases — During 1992-93, 4 leases containing 7,419 hectares were issued by way of direct purchase.

Primary Term Expiries — Shortly before a petroleum and natural gas lease reaches the end of its primary term, the lessee may apply to the Mineral Resources Division to have the lease continued, based on proven productivity. Petroleum and natural gas rights considered by the division to be productive are

Figure 6
Active Mineral Exploration and Development Agreements

	Number of Agreements				Thousand Hectares			
	March 31 1992	Issued	Cancelled	March 31 1993	March 31 1992	Issued	Cancelled	March 31 1993
Petroleum and Natural Gases Licences & Leases	62,534	4,845	6,598	60,781	26,228	2,866	3,276	25,818
Ammonite Shell Agreements	70	5	6	69	8	0	0	8
Oil Sands Leases	320	26	27	319	2,347	29	227	2,149
Coal & Coal Road Allowance	2,227	463	706	1,984	899	135	273	761
Metallic Minerals Exploration Permits	182	442	80	544	769	3,758	781	3,746
Metallic Minerals Leases	12	0	4	8	3	0	0	3
Other Minerals	143	10	19	134	29	10	5	34
Total	**65,488**	**5,791**	**7,440**	**63,839**	**30,283**	**6,798**	**4,562**	**32,519**

Figure 7
Petroleum and Natural Gas Parcels and Hectares (000) Sold



continued to the base of the deepest productive zone. Unproductive rights revert to the Crown.

During the 1992-93 fiscal year, 5,986 primary-term leases comprising 1,806,775 hectares, expired. Approximately 80 per cent, or 1,444,240 hectares, were not proven productive and reverted to the Crown. Figure 8 shows a breakdown of actions on expiring leases.

Figure 8
Expiring Primary Term Petroleum and Natural Gas Leases in 1992-93 Fiscal Year

	Leases	Hectares	Per Cent of Total Hectares
Continued Based on Proven Productivity	720	271,383	15.00
Continued Based on Drilling Operations Near End of Term	134	36,832	2.00
Continued As Potentially Productive	247	49,712	2.75
Term of Lease Extended	9	4,608	.25
Not Continued (Cancelled)	4,876	1,444,240	80.00
Total	**5,986**	**1,806,775**	**100**

Continued Leases — The Mines and Minerals Act provides for the monitoring of petroleum and natural gas leases that have been continued. When productivity of a lease is in doubt, the Minister may serve a one-year notice stating that the lands or rights will revert to the Crown unless the lessee can provide evidence of productivity. During the 1992-93 fiscal year, 1,291 non-productivity notices were served, affecting 384,746 hectares.

In addition, 1,017 non-productivity notices served in the 1991-92 fiscal year expired, affecting 220,950 hectares. These notices have a term of one year. As a result, 27 wells were drilled and an additional 5 wells were re-entered or recompleted prior to the end of fiscal 1992-93. Seventy-four per cent of the affected hectares reverted to the Crown and thereby became available for further redisposition.

Offset Drilling Obligations — When a well is drilled on freehold rights and is put on production, it has the potential to drain petroleum or natural gas from adjacent Crown mineral rights. This creates an offset drilling obligation for Crown leases. To protect the interests of Albertans, the Crown lessee is given the option of drilling a well, paying compensatory royalty in lieu of drilling, or surrendering lands or rights to satisfy the offset obligation.

During the 1992-93 fiscal year, 601 freehold oil wells were reviewed and 71 oil offset default notices were served. As a result of these notices, 19 lessees elected to pay compensatory royalty, 21 surrendered the petroleum and natural gas rights, 12 drilled wells, 18 notices were withdrawn and 1 remained outstanding.

During the 1992-93 fiscal year, 394 freehold gas wells were reviewed and 53 gas offset notices were served. As a result of these notices, 11 lessees elected to pay compensatory royalty, 31 surrendered the petroleum and natural gas rights, 9 drilled wells, 1 notice was withdrawn and 1 remained outstanding.

During the fiscal year, 1,312 petroleum and natural gas posting requests were reviewed and 25 oil offset and 12 gas offset notices were served. As a result, 12 lessees elected to pay compensatory royalty, 8 drilled wells, 15 surrendered the petroleum and natural gas rights and 2 notices were withdrawn.

Unit Agreements — A number of parties, including the Alberta government, can have an interest in a single oil or gas pool. These parties pool their interests by means of unit agreements which are useful tools for achieving the highest possible oil and gas recovery while ensuring that all parties recover an equitable share of the resource.

All proposed unit agreements in the province are reviewed, negotiated and executed on behalf of the Minister by the Mineral Resources Division. During the 1992-93 fiscal year, 19 new unit agreements became effective and 4 existing ones were enlarged. At fiscal year-end, the Alberta government was party to 599 units.

Oil Sands Leases — During the 1992-93 fiscal year, the Mineral Resources Division administered 320 oil sands leases. One-third of these leases are in their second 21-year term and will expire between 1996 and 2011. Each second-term lease is required to be in production at a specified capacity in order to enter its third term. These leases encompass approximately half of both surface-mineable and non-surface-mineable oil sands reserves. During the fiscal year, only 2 second-term oil sands leases produced at or above their prescribed capacity. Four other second-term leases produced at less than their specified capacities, while the balance did not produce at all.

The division recognizes that those prepared to commit to production during the third term should be allowed to retain reserves under lease.

The second-ever public offering of oil sands agreements was held in October 1992, with 14 leases and 4 permits sold for $216,000.

Coal and Other Minerals — The Mineral Resources Division administered 2,101 coal leases comprising 894,000 hectares during the 1992-93 fiscal year. This compares with 2,716 leases covering 956,000 hectares the previous year. The division did not issue any new coal leases.

The division received 3,100 applications for metallic mineral exploration permits, comprising 28 million hectares. The applications represent 56 per cent of the total area covered by Crown metallic and industrial mineral rights in Alberta. The exploration target for these applications is diamonds.

The division administered 70 ammonite shell agreements comprising 7,860 hectares of rights during the fiscal year and granted 9 applications for an additional 900 hectares of rights. Ammonite shell of jewellery quality is Alberta's gemstone. It is also a palaeontological resource under the Historical Resources Act.

A total of 99 quarriable mineral leases comprising 16,320 hectares were administered by the division during the fiscal year. In addition, the division administered 11 salt agreements comprising 5,100 hectares.

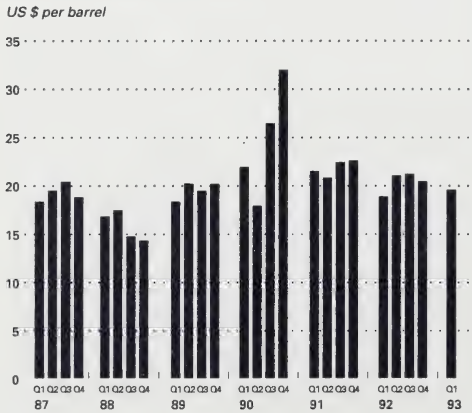
Oil

The average price for crude oil over the 1992-93 fiscal year was US$20.80 per barrel, using West Texas Intermediate sold at Cushing, Oklahoma as the benchmark. Although this average remained about the same as the previous fiscal year, prices fluctuated between $19 and $22.50, reflecting seasonal variations in supply and demand combined with short-term market imbalances.

By the beginning of the fiscal year, Kuwait had restored almost 1 million barrels a day (MMbpd) of the productive capacity it lost during the Persian Gulf conflict. Production continued to grow rapidly through the year, reaching the pre-conflict rate of 2 MMbpd by February 1993. This contributed greatly to excess global supplies which resulted in market instability. Iraq's exports remained suspended.

The countries of the former Soviet Union also influenced world oil markets. Gross domestic product declined by an estimated 18 per cent on average across these vast territories and crude oil production dropped to 9 MMbpd from 1988 levels of 12.6 MMbpd. Oil exports averaged 2 MMbpd, down significantly from 3.4 MMbpd in 1989. Figure 9 shows a comparison of crude oil prices by quarter since 1987.

Figure 9
West Texas Intermediate Crude Oil Prices



Markets and Pipelines — Total sales of Alberta crude oil rose 2 per cent in 1992. (These figures are calculated by the Energy Resources Conservation Board on a calendar-year basis.) Sales to domestic markets declined as Canada's weak economic recovery failed to stimulate growth in petroleum product demand. An 8-per-cent increase in deliveries to the U.S. midwest, Alberta's primary export market area, more than compensated for the lower domestic sales.

With the support of industry and the approval of the Minister of Energy, the Alberta Petroleum Marketing Commission coordinated efforts to reactivate the dormant Sarnia-Montreal section of the Interprovincial Pipe Line Ltd. system on behalf of Alberta producers. The link to Montreal — an important additional market for Alberta producers — was shut down in 1991. Industry agreed to share any extra costs incurred by the Commission in shipping crude oil to Montreal through an adjustment to Crown royalties.

For the second consecutive year, Alberta producers using the Interprovincial Pipe Line system to Eastern Canada and the U.S. had their monthly nominations (requests) to ship crude oil reduced because total nominations exceeded the capacity of the pipeline system. The average monthly reduction was 16 per cent.

Uncertainty over nominations hindered the marketing of crude oil by producers. Buyers became reluctant to contract for large volumes due to the possibility that their shipments would be subject to reduction. As a result, some sales required price discounts ranging from $0.25 to $1 a barrel to attract sufficient buyers.

The price discounting reduced industry revenues, partially offsetting potential gains generated by the 5-cent drop in the 1992 U.S.-Canada exchange rate. The lower exchange rate boosted the Canadian dollar value of Alberta's crude oil by about $1.50 a barrel.

Several pipeline expansions and new projects designed to increase capacity were proposed in 1992-93.

Production — Alberta's total production of crude oil and equivalent — conventional light, medium and heavy, bitumen, synthetic and condensate and pentanes — rose for the first time since 1988. Alberta's crude oil production totalled 1.4 million barrels a day in 1992, up 3.4 per cent from 1.36 million barrels a day in 1991. Declining light and medium production was more than offset by a combined increase in the other categories. A number of factors were responsible for the higher production:

- drilling increases stimulated by government programs;
- startup of Shell's Caroline project, which added significant condensate and pentanes production;
- advances in horizontal drilling and 3D seismic;
- improved economics for heavier crudes; and
- industry's property rationalization which transferred many non-active wells to smaller companies that are now working their new acquisitions.

Conventional light and medium oil production totalled 691 Mbpd (thousand barrels per day), down 2 per cent from 705 Mbpd in 1991. Light and medium crude represents 49 per cent of Alberta's oil production.

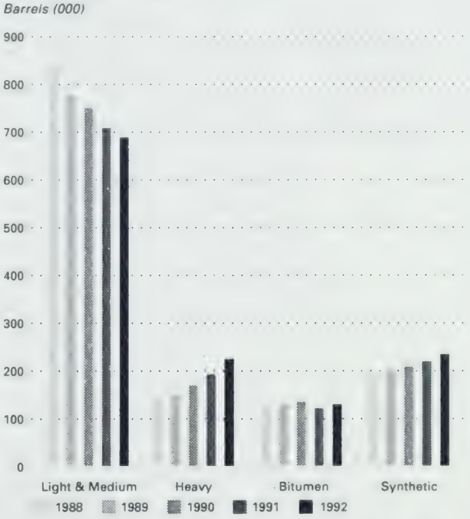
Conventional heavy oil production reached 225 Mbpd, up 16.6 per cent from 193 Mbpd in 1991. Bitumen production totalled 126 Mbpd, up 3 per cent from the 1991 level of 123 Mbpd. Production of synthetic crude oil climbed to 237 Mbpd, up 4.7 per cent from 226 Mbpd in 1991.

Pentanes plus volumes increased to 129 Mbpd, up 10.3 per cent from 117 Mbpd in 1991. Alberta's pentanes plus production is collected primarily as a co-product of natural gas processing. It is also collected as condensate at the wellhead and as a result of crude oil processing.

Figure 10 shows a 5-year comparison of crude oil production.

Conventional Reserves — Alberta's remaining reserves of conventional oil (crude oil that can be produced with normal drilling operations) totalled 2.78 billion barrels at the end of 1992, down 5.4 per cent from the previous year. Light and medium oil accounted for 86 per cent of the reserves and heavy oil made up the balance.

Figure 10
Average Daily Production of Crude Oil



During 1992, the proportion of remaining light and medium reserves decreased by about 7 per cent while the share of heavy oil increased by almost 5 per cent.

At today's rate of conventional oil production, Alberta's reserve-to-production ratio is just over eight years. The remaining ultimate potential production of conventional crude oil (including potential discoveries) is estimated by the Energy Resources Conservation Board at 6.22 billion barrels.

Non-conventional Oil Development — As the supply of conventional oil in North America is depleted, consumers will be able to turn to non-conventional sources of petroleum to avoid a growing dependence on resources outside North America. Fortunately, Alberta has huge deposits of oil sands that underlie about 77,000 square kilometres in the province and contain about 1.7 trillion barrels of oil in place.

In encouraging the development of this oil sands resource, the Government of Alberta's main objective

In Situ Recovery refers to in-place methods to extract the fuel component of a deposit. While shallow oil sands deposits can be removed by surface mining, dense heavy oils and deeply buried bitumen require in situ techniques before they can be brought to the surface. These include thinning the oil to make it mobile and application of pressure to make it flow.

is to promote sustainable and environmentally sensitive development using the best technology. Alberta's strategy of oil sands development is aimed at unlocking the massive resource potential for the long-term prosperity of the province.

Development Initiatives — Two initiatives were announced during the year to foster and support further development of the province's oil sands and heavy oil resources.

The first calls for the establishment of a National Centre for Upgrading Technology at Devon, bringing together research scientists from the Canadian Centre for Mineral Energy and Technology (CANMET) and the Alberta Research Council. This National Centre of Excellence is a joint venture between the Province of Alberta and the Government of Canada. The Centre is designed to produce a focused and collaborative national upgrading research effort and to foster research alliances among industry, government and the academic community. The objective is to ensure that upgrading technologies are in place to permit the timely and competitive development of hydrocarbon resources in Alberta and Western Canada.

The second initiative is the creation of a National Task Force on Oil Sands Strategies. The task force was created to identify new concepts, technologies and strategic approaches for further development of Alberta's oil sands resource. The task force is industry-led and includes representation from all industry stakeholders plus the governments of Alberta and Canada.

Non-conventional Activity — Prices for heavier crudes and bitumen strengthened in 1992-93, with the light-heavy oil price differential returning to the $6.50 to $7.50 range. Improved prices led to renewed interest by companies in developing their non-conventional production.

Syncrude Canada Ltd., the world's largest oil sands operation, broke its annual production record in 1992 by producing more than 65.4 million barrels of synthetic crude oil. Suncor Inc., the other integrated oil sands mining and upgrading operation, also had an excellent year with production of more than 20 million barrels of synthetic crude oil.

The $1.6 billion Lloydminster Bi-Provincial Upgrader was officially opened on November 20, 1992. The plant upgrades heavy oil and bitumen from Alberta and Saskatchewan with production of up to 46,000 barrels of synthetic crude oil a day. Although the Upgrader experienced cost overruns during construction and start-up losses, it surpassed production expectations and was operating at near capacity by the end of the 1992-93 fiscal year, providing a reliable market for Alberta heavy oil production. Producers saw increased heavy oil prices as a result of the new demand for feedstock.

Non-conventional Reserves — Remaining established reserves of crude bitumen that can be recovered with current technology from deposits under active development include 2.73 billion barrels for surface-mining projects and 0.3 billion barrels for in situ projects. These represent a supply of 23 years at 1992 production levels. The remaining ultimate potential for production of crude bitumen was 307 billion barrels at year-end 1992.

Industry Financial Health and Activity

The Department of Energy tracks the performance of the oil and gas industry as a whole as well as the various industry segments. The performance of individual companies within the industry is also monitored to identify trends and strategies.

The financial health and activity level in the upstream oil and gas industry changed dramatically during the 1992-93 fiscal year.

The industry's financial performance suffered during the second and third quarters of 1992 when gas prices dropped to new low levels. In 1992, the industry posted a loss of $1.5 billion, little changed from the $1.4 billion lost in 1991. Both losses were related to the writedown of assets. In 1991, those writedowns, connected with the reduced value of gas reserves, were spread across many companies. In 1992, the writedowns were restricted to a few large companies and could be traced to specific properties or reasons. The majority of companies experienced slightly increased profits in 1992 and cash flow for the industry as whole rose by 8 per cent.

The industry continued to rationalize and concentrate on lowering costs during 1992, reducing employment in Alberta's upstream industry by 2,200. The changes lowered direct operating costs by 5.3 per cent per barrel of oil equivalent and reduced overhead by 11.9 per cent per unit of output.

The low gas prices and poor financial outlook combined to reduce industry activity. In the first three quarters of 1992, drilling was down 13.7 per cent from the low levels of 1991 (the worst year in terms of wells drilled since 1971).

The rebound in gas prices, lower exchange and interest rates and the royalty changes announced by the government all combined to improve the industry's outlook in the fourth quarter of 1992. Drilling in the fourth quarter increased by 44 per cent over 1991 levels. This trend continued into the first quarter of 1993 when the number of wells drilled climbed to more than twice the 1992 level.

The increased activity levels of the fourth quarter could not make up for the slow second and third quarters. Overall industry capital expenditures in Alberta declined by 16.5 per cent from the previous year to $4.75 billion, partly due to the completion of the Caroline Gas Plant and the Lloydminster Bi-Provincial Upgrader.

This trend reversed itself during the first quarter of 1993 with oil and gas producers increasing their capital expenditures by 67 per cent over the first quarter of 1992. The rebound was also reflected in a 21-per-cent increase in cash flow and a tenfold increase in profitability for the first quarter of 1993. The higher activity levels were also accompanied by an increase of 1,000 employees in the upstream industry and 1,400 people in the drilling industry.

Natural Gas

Alberta's sales of natural gas increased by more than 12 per cent in 1992-93 from the previous fiscal year, largely because of increased exports to the U.S. and a return to normal cold winter weather in all markets which resulted in greater use of natural gas for heating.

Pipeline expansions continued to provide Alberta producers with increased access to markets in Eastern Canada and the U.S. Northeast. Of particular note was the completion of the Iroquois Gas Transmission System pipeline into New York State with its capacity of just over 600 million cubic feet a day (MMcf/d). Export pipelines operated at record levels and close to capacity because of rising U.S. demand.

After years of natural gas surplus and inventories that kept Alberta prices low, the supply-demand balance began to tighten. Previously constrained pipeline access to export markets began to be alleviated through pipeline expansions.

Prices — The average market price for Alberta natural gas in the 1992-93 fiscal year climbed to $1.51 per thousand cubic feet (Mcf) from $1.38 the previous fiscal year.

Spot prices for intra-Alberta gas sales rose dramatically in late 1992 and early 1993, signalling a reduction in the province's gas surplus. The surplus, built up under a period of price regulation, had kept prices below full costs for several years. Although the majority of intra-Alberta sales are based on fixed one-year prices, spot prices (a small part of the total intra-Alberta market) rose from less than $1 per Mcf in the winter of 1991-92 to more than $3 per Mcf the following winter.

Prices to the U.S. market rose steadily over the fiscal year. The increase reflected a much tighter supply-demand balance in the U.S. market, accentuated by low storage levels, the effects of Hurricane Andrew that hit the U.S. Southeast in the fall, and the "Blizzard of '93" that struck the Eastern U.S. in the spring.

Production — Natural gas production increased from 3.3 trillion cubic feet (Tcf) in 1991 to 3.7 Tcf in 1992. (Production and reserve figures are calculated by the Energy Resources Conservation Board on a calendar-year basis.) Export sales increased from 1.45 Tcf in 1991 to 1.7 Tcf in 1992. Sales to other Canadian provinces increased from 0.9 Tcf in 1991 to 1.0 Tcf in 1992, largely as a result of colder weather in Eastern Canada. Intra-Alberta sales rose from 913 billion cubic feet (Bcf) in 1991 to 973 Bcf in 1992.

Reserves — At the end of the 1992 calendar year, Alberta's remaining established reserves were estimated at 56.6 Tcf, down from 57.7 Tcf at the end of 1991. The natural gas sector, like other industries, is starting to operate at lower inventory levels than in the past. It is bringing its inventories more in line with its needs and relying more on exploration and development to meet ongoing demands.

Regulatory Issues

California — Discussions to resolve ongoing regulatory differences with the California Public Utilities Commission (CPUC) continued through the year. These differences arose from a number of CPUC decisions that threatened Alberta's existing long-term supply contracts for the California gas market.

The government implemented the NOVA Terms of Service Regulation on March 1, 1992. NOVA Corporation of Alberta maintains an extensive pipeline system, linking producing fields throughout Alberta to intra-Alberta delivery points and transmitting gas to connecting national and international pipelines. The Nova Terms of Service Regulation prevented the displacement of long-term firm gas supplies by shorter-term supplies until the long-term contracts were renegotiated.

Pacific Gas Transmission/Altamont — At the request of the Minister of Energy, the Energy Resources Conservation Board conducted a call for information on proposed expansions by Pacific Gas Transmission (PGT) and Altamont, two competing pipeline proposals to supply additional Canadian gas to California. The information gathered was designed to help industry in making decisions on the alternatives. Later in the year, Altamont announced a one-year delay of its project.

FERC 636 — In April 1992, the U.S. Federal Energy Regulatory Commission (FERC) issued Order 636, a major regulatory change that will result in the unbundling of services provided by U.S. pipeline companies. The intent of the order is to remove the competitive advantage that pipelines have enjoyed due to their integration of gas transportation and gas sales functions. This order has implications for Alberta sales to U.S. pipeline companies.

NOVA Daily Balancing — In December 1992, NOVA started a system of daily gas balancing on its pipeline system. It requires shippers on the pipeline to balance the amount of gas they put into the pipeline each day with the amount they remove. Previously, NOVA had a monthly balancing procedure that did not make a daily link between producers and their markets. Daily balancing is helping to shift the question of reliable gas supply from Alberta as a whole to individual producers and individual supply contracts.

Intra-Alberta Core Market Policy — In March 1993, the Department issued a discussion paper outlining a proposed policy that would give all consumers in Alberta the option to purchase natural gas either from their local utility company or from other sellers. Comments on the discussion paper were being received at the end of the fiscal year.

Removal Permits — An Alberta Gas Removal Permit is required before natural gas may be exported from the province. The Energy Resources Conservation Board and the Department of Energy work together to issue these permits. Just under 1,000 applications for gas removals were processed by the Department in the 1992-93 fiscal year, slightly below the previous fiscal year.

Coal and Other Products

Alberta has extensive coal resources and produces three general types of coal — subbituminous, bituminous thermal and bituminous metallurgical — at 11 major mining locations.

- Subbituminous coal is produced at 6 mines for use by Alberta utilities. These mines, all located in the Plains region, provide the basic fuel for most of Alberta's electric power generation.
- Bituminous thermal coal is produced at 2 mines. This high-heat value, low-sulphur coal is exported, primarily to Ontario and Japan where it is used in thermal power plants.
- Bituminous metallurgical coal is produced at 3 mines. Most of it is exported for use by the steel industry in Japan. Other markets include Korea and Brazil.

Coal Market Development — During the 1992-93 fiscal year, the Alberta government continued to work with the governments of other provinces, the federal government and industry to improve the competitiveness of Western Canadian coal in international and Ontario markets. Formed in 1987, the Action Committee on Western Canadian Low-Sulphur Coal consisted of the Deputy Prime Minister and the premiers of British Columbia, Alberta, Saskatchewan and Ontario.

The committee reviews all regulatory and fiscal aspects of coal transportation and supports the development of coal technologies and improved coal products. Alberta has assumed the lead role for most technical projects.

Research and Technology — The Department supported technology developments needed by the coal industry to remain competitive in domestic and international markets and to provide new products for these markets. Current research is focused on:

- reducing the emissions produced when fossil fuels are burned;
- development of "clean-coal" technologies for the next generation of coal-fired power plants; and
- development of new coal products and coal-based products and new uses for coal.

Emissions — Research continued into several types of clean-coal technologies capable of reducing the emissions produced when coal is burned. One of these is Integrated Gasification Combined Cycle (IGCC). A preliminary design for a commercial-scale IGCC plant has been prepared. Processes for capturing, using and disposing of carbon dioxide are also being studied. During the 1992-93 fiscal year, the Department began a preliminary study on Full Fuel-Cycle Emissions Analysis, a method for determining the complete emissions profile of various energy sources for electric power generation.

Coal/Oil Upgrading — For nearly a decade, researchers in Alberta have been developing a process called coal/oil agglomeration. In the 1992-93 fiscal year, pilot-scale testing provided the operating information necessary for possible future construction of a commercial-scale plant for this process. Coal/oil agglomeration enhances the energy content of the coal, while reducing the emissions of ash and sulphur produced when the product is burned. Heavy oil used in the process is also upgraded to a more valuable oil.

Hydrogen Research — The Alberta Hydrogen Research Program, funded jointly by industry and government, aims to make Alberta's energy industry more competitive. The program's overriding objective is to use hydrogen as a principal link for integrating the energy resource industry and developing Alberta's industrial base. Thus far, 32 research projects have been carried out. The program is focused on methods for reducing the cost of hydrogen production and opportunities to use hydrogen in a more efficient manner in existing or new industries in Alberta.

Sulphur — Alberta is one of the largest sulphur-producing regions in the world, with output totalling 5.8 million tonnes in the 1992 calendar year, up 3.5 per cent from 1991. More than 5.2 million tonnes or 90 per cent of Alberta's sulphur production comes from gas processing facilities. Oil sands plants recovered 0.6 million tonnes and crude oil refineries 0.02 million tonnes.

Alberta exports much of its sulphur for use in manufacturing sulphuric acid and fertilizers. A drop in world demand for sulphur, coupled with an increase in production in a number of other countries, resulted in depressed sulphur prices. The price of sulphur dropped to $21 a tonne in 1992, down 62 per cent from $55 a year ago.

Alberta's remaining established reserves of sulphur total 100 million tonnes. Of this total, 84 million tonnes are recoverable from natural gas reserves and 16 million tonnes from minable oil sands deposits.

Mineral Development Agreement — The Canada-Alberta Partnership on Minerals, a three-to-four-year program jointly administered by the federal and Alberta governments, funded research during the 1992-93 fiscal year to help identify and assess the province's metallic and industrial mineral potential.

Research reports and/or maps on 24 projects funded in the first year of the Partnership were prepared and released to industry, scientists and other interested parties. Prepared by project researchers, the reports cover a wide range of general as well as region-specific mineral-related research, mapping and economic development activities. Final funding allocations will be made by March 31, 1995, allowing projects to be completed by March 31, 1996.

Royalties

A comprehensive review of Alberta's oil and gas royalty systems was conducted in 1992. The review resulted from significant changes in the business environment, industry's financial situation and the Western Canadian Sedimentary Basin that have occurred since the 1970s when royalty regimes were put in place in anticipation of high oil and natural gas prices and significant exploration potential. The review recommended changes to make Alberta's oil and gas royalty system consistent with the new environment and responsive to market conditions.

As a result of the review, the Government of Alberta announced the most sweeping oil and natural gas royalty policy changes since the 1970s. The changes were designed to help stimulate the province's energy industry to produce increased activity, employment and investment into the next century. Highlights of the changes:

- Greater price sensitivity in the new gas and new oil royalty formulas, effective January 1, 1993. This means that rates are higher when prices increase and lower when prices go down.
- The royalty formula was indexed to the Gross Domestic Product to compensate for the effects of inflation on market prices.
- Separate par prices for heavy oil and non-heavy oil were introduced.
- All oil from pools discovered after October 1, 1992 will have royalties about one-third less than oil from older pools, effective January 1, 1993. This reduction recognizes that remaining undiscovered oil is likely to be from smaller remote pools which cost more to find and develop.
- The one-third lower royalty on oil production from new pools and the general reduction in royalty rates are designed to provide a continual incentive for exploration and development.
- A permanent one-year or $1-million holiday on royalty payments for third-tier exploratory oil wells was introduced effective October 1, 1992. This replaces the temporary exploration holiday program introduced in November 1991.
- Royalty rates were set for new oil and gas, effective January 1, 1993. The reductions will be worth $85 million each for both new oil and new gas during 1993.
- The temporary re-activated oil well royalty holiday that was to expire April 1, 1993 became permanent on October 1, 1992. The royalty holiday production limit was increased to 50,000 barrels.
- A permanent low-productivity oil well policy was introduced, effective October 1, 1992. This policy encourages well workovers of aging, low productivity wells by protecting wells from royalty rate increases and reducing royalties on incremental production.
- A permanent horizontal re-entry oil well royalty reduction policy was introduced, effective October 1, 1992.

Coal Royalties — A new royalty structure for coal, approved by Cabinet in September 1992, is designed to simplify administration of royalties. It replaces a royalty system that went into place in 1976 when world demand and prices for coal were high.

A key feature of the new structure is the distinction made between bituminous and subbituminous coal. Bituminous coal, which is mainly exported to Ontario and Japan, is a higher-quality product found in the mountains and foothills of Alberta. Coal found east of the foothills is classified as subbituminous and is used for generating electricity in Alberta.

Under the new royalty structure, bituminous coal mines will pay a royalty of one per cent of their gross revenues as calculated at the mine site. Bituminous coal mines that have recovered their initial investment will pay an additional royalty of 13 per cent of their annual net revenue.

A royalty rate based on a fee per tonne will be used from July 31, 1992 to December 31, 1993, for

Horizontal Re-entry: The horizontal re-entry of aging vertical wells allows greater recovery of oil than through the use of other technologies. It requires heavy up-front investment.

Low Productivity Oil Well: For purposes of the royalty adjustment, a low productivity oil well is a well with average production less than 460 barrels a month (15 barrels a day) during the latest six months, with production exceeding zero.

New Oil: Conventional crude oil generally from pools discovered on or after April 1, 1974 and before October 1, 1992.

Old Oil: Conventional crude oil, generally from pools discovered before April 1, 1974.

each of the province's six subbituminous coal mines. A uniform royalty rate will be established starting January 1, 1994, for subbituminous coal at a rate to be determined by the Minister of Energy based on conditions that exist at the time.

Gas Royalty Simplification — In October 1992, the Cabinet approved the principles of a simplified natural gas royalty administration. The strategy, part of sweeping changes to Alberta's gas royalty system, is designed to produce significant annual savings for industry and government by reducing the administrative burden and ensuring that the Department continues to collect the Crown's share of production. Average costs (corporate average capital cost and deemed operating cost) will be used to determine the Crown's share of processing costs.

Under the new system, a reference price will be used for valuing gas at the plant outlet at the time of production. This avoids any need to link particular sales contracts to particular production units. Producers will be given a one-time option of valuing gas at a corporate average price which may be no less than 90 per cent of the reference price.

The simplified program, to be effective January 1, 1994, is intended to reduce the required industry filings by 80 per cent.

Third Tier Oil: Conventional crude oil, generally from pools discovered after September 30, 1992.

Electricity

The generation of electricity in Alberta increased by almost 7 per cent in the 1992-93 fiscal year from the previous fiscal year. The main fuel source for electricity generation in Alberta is coal, accounting for 88 per cent of total generation. Most of the remaining generation is from natural gas and hydro facilities. A small amount of electricity (less than half of 1 per cent of total generation) is generated by projects under the Small Power Research and Development Program and in isolated areas of the province using fuel oil.

Changes in Electricity Bills — Electricity bills showed moderate increases during the 1992-93 fiscal year as indicated in Figure 11. The increases resulted partly from the 1992 addition into the ratebase of the Sheerness 2 generating unit, jointly owned by TransAlta Utilities and Alberta Power. The costs of new generating facilities are phased in over two years. The balance of the increase was due to new transmission and distribution facilities and increases in operating costs.

Figure 11
Increase in Electricity Bills — March 31, 1992 to March 31, 1993

	Residential	Commercial	Industrial	Farm
TransAlta Utilities (retail)	3%	3%	3%	3%
Alberta Power	0%	1%	6%	2%
City of Calgary	3%	3%	3%	–
City of Edmonton	10%	9%	9%	–

Note: Increases in electricity bills vary significantly depending on the time period chosen. For example, Edmonton Power did not have an increase in the 1991-92 fiscal year while the other utilities did.

Electric Energy Marketing Act — The Electric Energy Marketing Act (EEMA) was implemented in 1982 with a primary objective of reducing electricity rate disparities throughout the province. The basic concept of EEMA is to average the costs of generation and transmission facilities province-wide — independent of utility ownership, franchise boundaries or geographic location.

The cost of electricity for consumers is only partly based on the wholesale EEMA cost. The rates for customers served by Alberta's two investor-owned utilities, Alberta Power and TransAlta Utilities, are approved by the Public Utilities Board. Municipally owned utilities set the final rates for their customers. Consumers' electricity bills reflect the common wholesale EEMA price, as well as the distribution costs and profits of the utilities.

A seven-member panel established to review the Electric Energy Marketing Act (EEMA) invited submissions from Alberta organizations and individuals. More than 550 organizations and individuals filed written submissions. The panel also held public hearings in Lethbridge, Grande Prairie, Edmonton, Fort McMurray and Calgary during May and June 1992.

The panel's report, publicly released in February 1993, concluded that while EEMA has been effective in reducing rate disparities across the province, there is an element of unfairness in EEMA's pricing formula. The panel recommended changing this formula to partial equalization of generation and transmission costs. Another key recommendation was to pool and fully equalize all provincial and non-rebated federal income taxes on investor-owned utilities.

The report was sent to all those who had made submissions. They were asked to provide comments on the panel's recommendations.

Small Power Research and Development — The principal objective of the Small Power Research and Development Program is to encourage production of electricity from renewable sources and to determine the role of renewable small power in meeting Alberta's future requirements. The program has an allocation of 125 megawatts of renewable small power and provides an incentive power purchase price.

In June 1992, the Small Power Research and Development Regulation was amended to provide deadlines for receiving final power allocation approvals. Cabinet also announced that no further applications would be accepted.

A total of 21 projects received allocation, representing a variety of renewable energy technologies including wind, solar and small hydro and energy from biomass, peat and waste wood.

Regulatory Review — A discussion paper entitled "Regulatory Framework for the Electric Power Industry" was released in April 1992. It outlines options identified by a task force to improve the existing regulatory framework, and offers alternatives for the future structure and regulation of the electric power industry in Alberta.

Stakeholder responses, received at the end of July 1992, paralleled the diversity of views expressed in the Electric Energy Marketing Act (EEMA) hearings in May and June 1992. Submissions said that recommendations on the scope and nature of the planning process should not precede a decision on the future of EEMA. There was general agreement on the need to clarify and better coordinate the regulatory responsibilities of the Energy Resources Conservation Board and the Public Utilities Board. A merger of responsibilities for all electricity regulatory matters under a single board was identified as an alternative to address this concern.

In the fall of 1992, the government announced its intention to study the merits and logistics of amalgamating the two boards.

In February 1993, a steering committee was formed with members from the Regulatory Review Task Force and representatives from the Clean Air Strategy for Alberta (CASA) community to collaborate on a response to CASA Priority Task B3. This is one of 14 priority tasks endorsed by Cabinet in May 1992. Under Priority Task B3, the Department of Energy was directed to ." . . immediately extend its current Regulatory Review of the Electric Power Industry to cover Energy Efficiency and Demand-Side Management (DSM) considerations."

The committee prepared material for a workshop which provided stakeholders with an opportunity to help identify barriers to DSM. The committee will review these potential barriers and develop recommendations as to how they should be addressed.

Fuel Use Review/CASA Priority Task D3 — The Fuel Use Policy was created in May 1974, when the government endorsed an April 1973 recommendation by the Energy Resources Conservation Board (ERCB) stating that "coal is a preferred fuel to natural gas for baseload electric power generation." Under Alberta legislation, proposals for new power plants must be approved by the ERCB. If approved, the proposal advances to Cabinet for final authorization. The policy does not preclude the use of natural gas or other fuels, but represents a standard to be used when considering applications.

In March 1992, the government announced a review of the Fuel Use Policy, noting that key factors which had mitigated against the competitiveness of natural gas had changed.

In June 1992, the government announced its endorsement of 15 Priority Tasks under the Clean Air Strategy for Alberta (CASA) initiative. Priority Task D3, which concerned alternative electricity sources, was to be coordinated with the Fuel Use Policy Review.

In recognition of this, the Fuel Use Policy Review and CASA D3 were combined in a two-phase process. In Phase I, the ERCB was asked to review whether the circumstances that led up to the 1974 policy had changed. A Technical Advisory Committee began work on a series of technical background papers in anticipation of Phase II. The second Phase, which is expected to begin in the fall of 1993, will focus on the D3 task of assessing the range of available mechanisms to achieve flexibility in the choices of electricity generation which contribute to air quality. A multi-stakeholder Steering Committee comprising electric utilities, independent power producers, natural gas and coal producers, environmental groups and consumer groups will be formed to collaborate on a response to CASA D3.

Energy Efficiency and the Environment

The Department of Energy addresses environmental concerns resulting from the development, production and consumption of energy resources. The focus is on integration of resource development and environmental protection and on development of initiatives to manage atmospheric emissions associated with energy production and use.

Integrated Resource Management — The Department subscribes to the philosophy of integrated resource management to ensure that resource-use decisions are made in the broader context of multiple land use. This presents the Department with the opportunity to review land and resource management policies, programs and objectives of participating government agencies. Such reviews ensure that programs are consistent with the government's overall plan for the management of Alberta's mineral resources. The Department reciprocates by sharing information on energy or mineral resource management initiatives with these agencies.

Integrated resource management is supported by the Department through a number of methods, the most formal of which is participation in the province's Integrated Resource Planning Program. The Mineral Resources Division coordinates the Department's participation in the program.

In the 1992-93 fiscal year, the division worked to maintain opportunities for industry to gain access to, explore for and develop the mineral resources in each planning area. Progress was made on 12 Integrated Resource Plans (IRPs), 1 of which was approved for implementation. As well, the division participated in two major plan reviews which began in 1992. In all, 29 IRPs have been approved.

The Department also participates in integrated resource management through a number of interdepartmental referral processes. During the year, 86 referrals were received for review and comment.

These referrals included: 1 reclassification of land pursuant to current coal policy; 4 preliminary disclosures to government by proponents of major energy or mineral development proposals; 3 Environmental Impact Assessments; 22 applications for surface dispositions for commercial tourism and recreation leases; 14 applications to designate lands for uses such as future parks, ecological reserves or wilderness and natural areas; 1 industrial development application; 15 land transfer requests; and 26 miscellaneous applications. Each referral was reviewed for its impact on access for existing or proposed mineral development activity.

The Mineral Resources Division also participated in 3 regional integrated decisions (RIDs), which are similar to integrated resource plans but with a local focus. The RIDs were designed to resolve oil and gas development access issues in environmentally sensitive and ecologically significant areas.

Clean Air Strategy for Alberta — In June 1992, the Alberta government approved strategic recommendations stemming from the Clean Air Strategy for Alberta (CASA) consultations. CASA brought together a diverse group of stakeholders over 18 months to develop a consensus-based strategy and encourage public discussion about gaseous emissions resulting from the production and use of energy in Alberta. Fifteen priority tasks recommended by CASA were approved by the Alberta government for development of implementation plans. The Department of Energy provided CASA with secretariat support and coordinated the work of the priority task groups.

CASA's key recommendation called for development of a comprehensive air quality management system. The Department worked on a stakeholder transitional steering committee, which was formed to develop the system.

The Department chairs the CASA Interdepartmental Coordinating Committee, responsible for the priority tasks. The Department

Integrated Resource Plans represent a comprehensive and collective approach to decision-making on the use of public land and resources. Information about resources and land-use activities is considered in the process, as are the views of interested government agencies, municipal authorities, interest groups and the public.

also chairs 7 CASA priority task groups which address energy efficiency, electricity policy, and national and regional coordination.

Air Quality Forum — Effective air quality management requires sound scientific and technical information. In September 1992, the Department of Energy organized the Air Quality Forum: Tools and Techniques for Improved Decision-Making with representation from the energy sector, the academic community and government. It met monthly to discuss air quality information needs. The forum developed a process to improve environmental decision-making with particular emphasis on assessing options. Forum participants identified information, tools and expertise required at each stage of decision-making, with emphasis on the needs of the Clean Air Strategy for Alberta.

Economic Instruments Collaborative — The Department of Energy participated as an observer/ advisor on the national Economic Instruments Collaborative, initiated by the Canadian Association of Petroleum Producers, TransAlta Utilities, and the Alberta Environmental Network. Stakeholders discussed the merits of market-based instruments for environmental protection. The Collaborative is developing recommendations on the general design and application of economic instruments for managing emissions associated with acid deposition, ground-level ozone and climate change.

International Environmental Issues — Throughout 1992-93, the Department of Energy was actively involved in developing responses to several international environmental developments that could potentially affect the energy sector in Alberta. The Department coordinated Alberta's input into Canada's ratification of the Framework Convention on Climate Change. It also provided input into other documents from the United Nations Conference on Environment and Development such as Agenda 21 and the Biodiversity Convention. Other international environmental agreements reviewed by the Department included environmental protocols associated with the European Energy Charter, renegotiations to the European Economic Commission Sulphur Dioxide Protocol and the North American Free Trade Agreement's proposed environmental side agreement.

Environmental Legislation — The Department of Energy was involved during 1992-93 in consultations for developing regulations to the Alberta Environmental Protection and Enhancement Act. The Department worked with representatives of the energy industry, the Energy Resources Conservation Board and Alberta Environment with the goal of creating sound environmental legislation sensitive to the needs of the energy sector.

Provincial Territorial Advisory Committee on Climate Change — The Department of Energy participated in numerous activities related to climate change at both the national and international levels in 1992-93. It was an active participant in the Provincial-Territorial Advisory Committee on Climate Change (PTAC), initially established to advise the federal government on issues related to the drafting of an international climate change convention. In May 1992, the Department represented PTAC at the final meeting of the International Negotiating Committee, responsible for drafting the Climate Change Convention.

The Department was also active in national climate change activities. Task groups on inventories, forecasting and assessment were established in November 1992. The Department participated in all three groups and co-chaired the Assessment Task Group. These groups are helping to develop the tools and mechanisms needed to meet the objectives of the Climate Change Convention.

National Coordination — The Department of Energy and Alberta Environment developed a proposal to formalize interactions between federal and provincial Energy and Environment departments on atmospheric environment policy. This resulted in the establishment of a National Air Issues Steering

Committee, consisting of deputy ministers of Environment and Energy departments, reporting jointly to the Canadian Council of Energy Ministers and the Canadian Council of Ministers of the Environment. This new structure will help in the development of coordinated air issue management plans and strategies.

Southwest Alberta Renewable Energy Initiative — SWAREI, the largest renewable energy program in Western Canada, was established in 1989 to promote development of the abundant wind and solar energy resources in the Pincher Creek-Crowsnest Pass area and to help diversify the economy of the region.

During 1992-93, 2 projects were commissioned and 1 was completed. In addition, 1 new project was approved, bringing the total number of SWAREI projects to 11. Over the year, the Information Centre for the Alberta Office of Renewable Energy Technology in Pincher Creek fielded more than 600 enquiries, provided 3 workshops on renewable energy and energy efficiency, held an open house and participated in related conferences, expositions and trade fairs.

Energy Efficiency

The Department of Energy encourages and promotes the wise and efficient use of Alberta's energy resources. It develops and operates energy efficiency awareness, information and education services for all types of energy users, including the general public, business, industry, the transportation sector, students and teachers.

Analysis and Policy — Policy work focused on implementing specific priority objectives of the Clean Air Strategy for Alberta, particularly those pertaining to energy efficiency analysis and energy efficiency in government facilities.

Information Services — The Energy Matters telephone inquiry service received 4,100 calls on home energy efficiency questions during 1992-93. More than 93,000 copies of publications were distributed through building supply and hardware stores and other outlets.

Technical Services — Energy audits, conducted on request from business, industry and institutions, identified potential energy-efficiency improvements through on-site analysis. Energy Efficiency Branch staff used a computer-equipped bus to monitor energy use, determined steps to reduce energy costs and made recommendations. In 1992-93, 61 buildings were visited and potential annual energy cost reductions of $2.4 million (9.6 per cent of total annual costs) were identified, involving easily implemented measures. More than 2,300 buildings have been audited since this program was introduced 12 years ago.

A transportation energy audit program has been offered to vehicle fleet operators for the last four years. To date, 26 fleets of various types have been analyzed, identifying more than $560,000 in potential annual savings. During the year, approximately 77,000 Alberta drivers received fuel economy calculators and other materials to help monitor and improve fuel efficiency.

Education Services — More than 16,500 Alberta students received energy-saving information in their classrooms through dramatized presentations by department staff. Alberta educators received instructional and curriculum resources, including 2,100 instructional resource kits, to help them teach the importance of energy efficiency to more than 59,000 students.

In 1992-93, 1,800 schools in Alberta received a copy of "Somebody Should Do Something About This!," a teacher's resource book on energy and the environment.

Finance and Administration

In the 1992-93 fiscal year, this core group provided centralized services for a variety of financial and administrative functions required by the departments of Energy, and Forestry, Lands and Wildlife. Over the year, the executives of Finance and Administration reviewed the business of their organization. Through this strategic planning process, mission and mandate statements, as well as value and operating philosophy statements, were developed.

Automated Information Systems — This area provides information technology support, including specialized technical expertise and support for information and office systems. During the 1992-93 fiscal year, it supported 32 major computer systems for the departments. In addition, the Mineral Revenues System was significantly improved, planning for a system to support the new gas royalty regime was started and a new oil and gas sales system was successfully launched. The telecommunications network and integrated office system for both Departments were also improved.

Financial Services — Financial Services is responsible for the Accounts Payable/Receivable functions and administers the department-wide forecast and expenditure monitoring system. During the past year, major phases were completed in a move to replace the Main Accounts Receivable System with the Corporate Accounting and Reporting System. The creation of a computer link with other departmental systems, which was part of the replacement, enabled other areas to provide data electronically for use in producing invoices. It also allowed electronic access to revenue and receivable information.

Human Resources — This area provides services related to staffing, classification, wage and salary administration, employee relations, staff and organizational development, human resource information management, security and occupational health and safety. During the past fiscal year, ongoing improvements were made to information systems to increase efficiency in supplying timely human resource information to assist departmental operations. The area also provided assistance to divisions involved in reorganization. As well, Human Resources participated in initiatives related to employee career development, the government-wide women's program, plain language, training assessments and performance management.

Internal Audit — Internal Audit examines the financial activities of both departments to ensure that internal accounting and operating controls function properly. Compliance and financial audits were completed over the past year, as were operational management audits and audits of application systems, development projects, computer facilities and the information technology infrastructure. Emphasis was placed on reviewing the major systems being developed. This included the project audit on the development and start-up of the major phases for the Corporate Accounting and Reporting System.

General Services — This area is responsible for providing a wide range of administrative, information and accommodation services to the two departments. As part of this, the first phase of a comprehensive reprographics strategy was brought in, which involved acquiring equipment for electronic access to printing through the departments' communications network. Library Services entered into a partnership with the University of Alberta and other government and local libraries to share resources and a common automated library system.

The Records Management Program won the International Olsten Award for Excellence in Records Management in the major government category. It was the first Canadian government agency to win this award.

Crown Land Data Services established a computer link to the Corporate Accounting and Reporting System, which provides on-line integration of the two departments' leasing and financial transactions. It also entered into an agreement with Land Information Alberta to provide on-line access to search products on the Land Status Automated System for electronic distribution to the public through the Land Related Information Systems Gateway.

Financial Statements

Alberta Department of Energy
Statement of Revenue
for the Year Ended March 31, 1993

	1993 ($000)	1992 ($000)
Taxes:		
Freehold mineral rights tax	72,609	75,215
Other	1	1
	72,610	**75,216**
Non-Renewable Resource Revenue:		
Crude oil royalty	$1,008,545	$1,037,611
Natural gas and byproducts royalty	1,069,313	839,277
Synthetic crude oil & bitumen royalty	64,941	30,590
Coal royalty	15,992	26,491
Bonuses and sales of Crown leases	167,485	261,503
Rentals and fees:		
Petroleum and natural gas	88,617	92,767
Oil sands	7,472	8,314
Coal	3,996	3,086
Other	2,430	653
Allocation to Natural Gas Rebates Fund		(710)
Other	10	10
	2,428,801	**2,299,592**
Transfers from Government Enterprises:		
Alberta Petroleum Marketing Commission	4,245	4,260
Other Revenue:		
Refunds of expenditure	153	166
Miscellaneous	711	656
	864	**822**
Total Revenue	**$2,506,520**	**$2,379,890**

Extracted from the Alberta Public Accounts 1991-92, and Public Accounts 1992-93, Volume 2.

Alberta Department of Energy
Statement of Departmental Expenditures
For the Year Ended March 31, 1993

	1993 ($000)	1992 ($000)
Finance and Administrative Services	$ 12,194	$ 6,799
Mineral Management		
Mineral Resources	7,723	7,474
Mineral Revenues	15,179	14,341
Markets, Supply and Industry Analysis	3,063	3,419
Sustainable Energy Development	6,963	7,218
	32,928	32,452
General Support Services	1,263	1,304
Special Warrants and Special Programs		
Assistance for Oil Sands Projects	0	25,189
	$ 46,385	$ 65,744

Extracted from the Alberta Public Accounts 1991-92, and Public Accounts 1992-93, Volume 2.

Note 1: Statement Of Expenditures: Alberta Oil Sands Equity, Alberta Oil Sands Technology and Research Authority, Alberta Petroleum Marketing Commission and Alberta Public Utilities Board are not included in the Statement of Expenditures.

For additional copies, contact:

Communications Branch
Alberta Energy
14th Floor, Petroleum Plaza, North Tower
9945 – 108 Street
Edmonton, Alberta
T5K 2G6
Telephone: (403) 427-8697
Fax: (403) 422-0800

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